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Structure of the Dynamic Integrated Economy/Energy/Emissions Model: Electricity Component, DIEM-Electricity

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INTRODUCTION TO THE DIEM-ELECTRICITY MODEL

This paper describes the structure of, and data sources for, the electricity component of the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), which was developed at the Nicholas Institute for Environmental Policy Solutions at Duke University. The DIEM model includes a macroeconomic, or computable general equilibrium (CGE), component (see Ross 2014) and an electricity component that gives a detailed representation of U.S. regional electricity markets. The electricity model (DIEM-Electricity) discussed below is the June 2013 version of the model. It can be run as a stand-alone model or can be linked to the DIEM-CGE macroeconomic model to incorporate feedbacks between economy-wide energy policies and electricity generation decisions, and/or the interactions between electricity-sector policies and the rest of the U.S and global economies.

Broadly, DIEM-Electricity is a dynamic linear-programming model of U.S. wholesale electricity markets. The model represents intermediate- to long-run decisions about generation, capacity planning, and dispatch of units. It minimizes the present value of generation costs (capital, fixed O&M, variable O&M, and fuel costs) subject to meeting electricity demands.[1] Within each year's annual demand, the model also considers the timing of demand across seasons and times of day. Existing generating units are aggregated into model plants. New plant options are also included based on costs and operating characteristics from the *Annual Energy Outlook* (EIA 2013), which also provides demand forecasts and fuel prices. Model plants are dispatched on a cost basis to meet demand within each region in the model through 2050 (or later).

The model provides results for generation, capacity, investment, and retirement by type of plant. It also determines wholesale electricity prices, production costs, fuel use, and CO_2 emissions. Currently, the model can consider, at a national policy level, renewable portfolio standards, clean energy standards, caps on electricity-sector CO_2 emissions, and carbon taxes. Under development are additional features to facilitate investigations of criteria pollutant regulations.

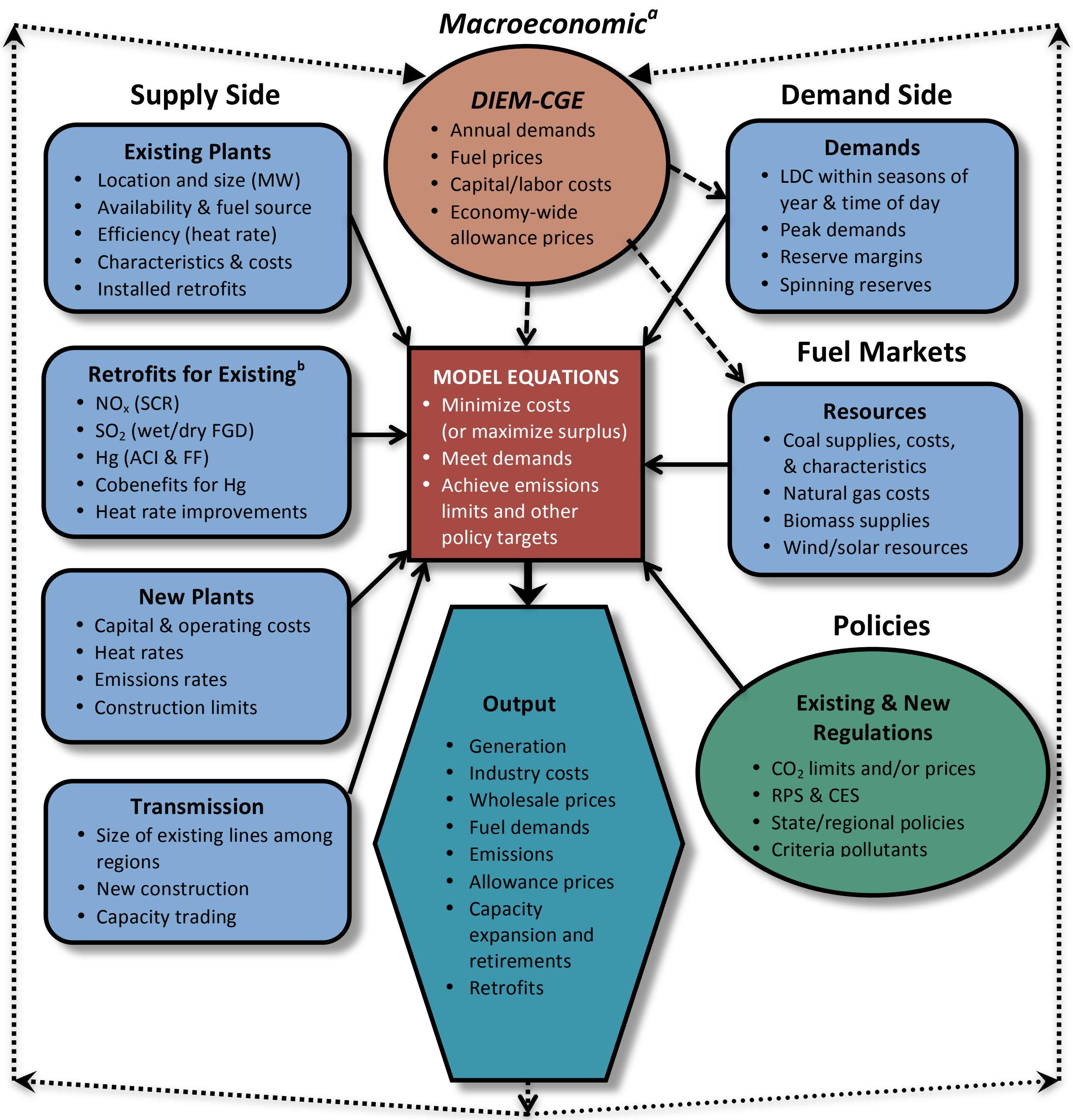
OVERVIEW OF DIEM-ELECTRICITY

As shown in Figure 1, the model incorporates a wide range of data on the characteristics and costs of generating plants that supply electricity to the national/regional grid. The electricity supplies are matched with demand levels expressed on a seasonal and time-of-day basis (through regional load duration curves). Units are aggregated into model plants to reduce the dimensionality of the mathematical programming problem. Model plants are dispatched on an economic basis, considering operating costs, fuel prices, emissions targets, and costs of new units, among other factors. In general, the model structure that ensures supplies meet demands is an objective function that minimizes generation costs subject to the following types of constraints:

- generation + net imports => demand by load segment
- capacity => peak demand × (1+ reserve margin)
- generation by plant p in each load segment <= capacity × hours × availability
- capacity in time t = capacity in time t-1 + investment in time t-1 - retirements in time t
- emissions <= any specified caps
- generation by type (e.g., renewables) => any policy targets
- any other constraints related to generation, interregional transmission, system reliability, emissions, or investment limits

[1] When linked to DIEM-CGE, the objective function is adjusted to maximize welfare as the difference between producer costs and consumer benefits (the area under the annual demand curve from the macroeconomic model). This paper largely focuses on the stand-alone electricity model; see Ross (2014) for additional details on how it can be linked to the CGE model.

Figure 1. Overall structure of the DIEM-Electricity model



[a] DIEM-Electricity can be run as a stand-alone model, or it can be linked to the DIEM-CGE model to incorporate macroeconomic feedback effects between the electricity sector and the rest of the U.S. economy with regard to electricity demand levels, fuel prices, and economy-wide emissions policies such as carbon caps or taxes.
[b] Retrofits for criteria pollutants and the associated characteristics of coal supplies are under development.

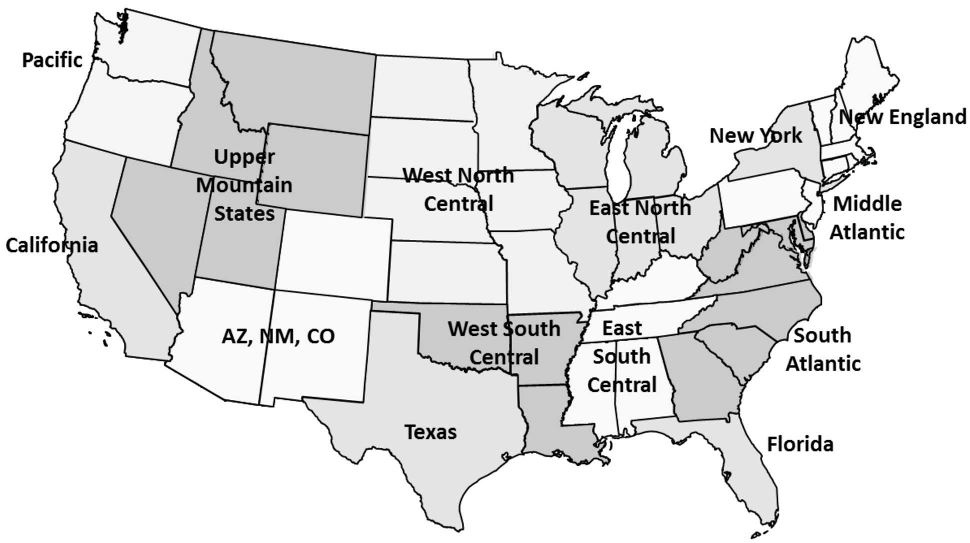
Table 1 summarizes the data sources used in DIEM-Electricity and what they provide.

Table 1. Data sources

Source	Category	Data
IPM NEEDS v.4.10 (IPM 2010)	Existing units	Type, size, location, heat rate, existing equipment
	Operating costs	Fixed and variable O&M for existing units, costs of some specialized resources such as geothermal and wind
	Capital charges	Charge rates used to annualize new unit investments
	Unit availability	Percentage of the year that each unit can generate electricity
	Demand curves	Hourly demand for 32 regions for a representative year
	Reserve margins	Regional margins over peak demands
	Resource availability	Wind, geothermal, landfill gas, and biomass resource supplies
	Transmission	Ability for electricity to flow among regions
	Retrofits	Costs of effectiveness of various environmental retrofits
Annual Energy Outlook 2013 (EIA 2013)	Annual demands	Forecasts of regional electricity demands through 2040
	Fuel prices	Forecasts of regional fuel price growth through 2040
	New units	Costs and characteristics of new generating units
	Coal supplies	Coal ranks, prices, and characteristics by supply region
State Energy Data System (EIA 2010)	Annual demands	State-level electricity demands (for aggregation to regions)
	Fuel prices	State-level fuel prices paid by electricity generators
NREL ReEDS (Short et al. 2009)	Seasonal characteristics	Seasons of year and times of day for load curves

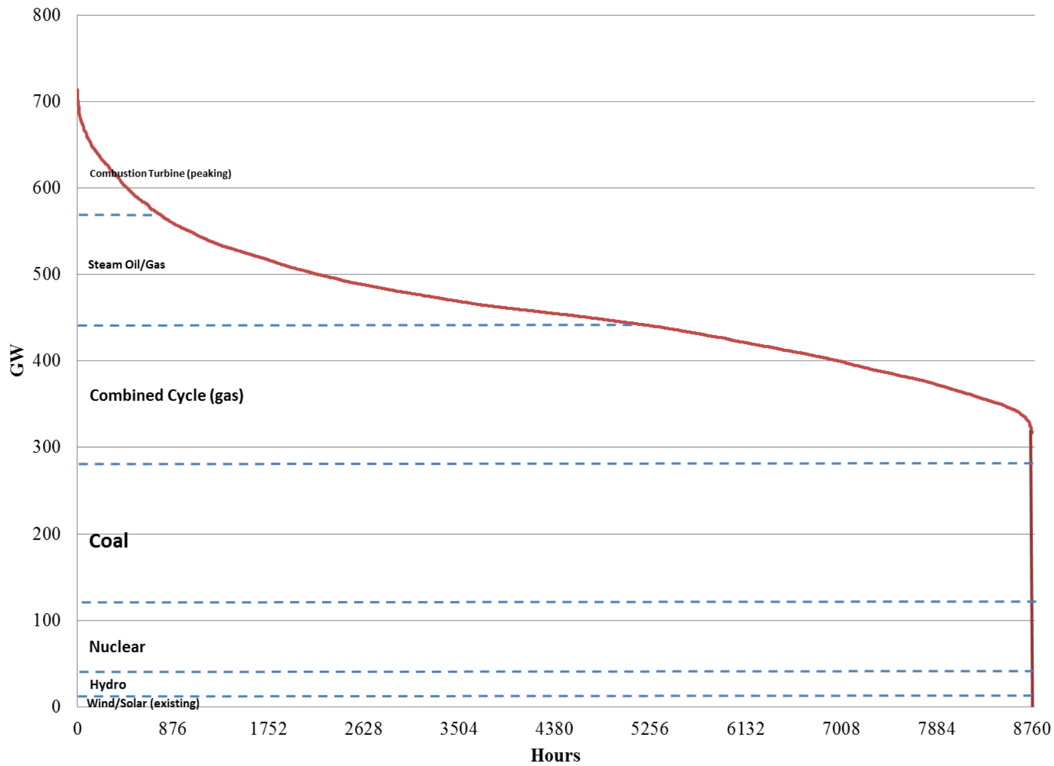
The model has 14 regions defined along state lines that approximate distinct electricity markets (state boundaries are necessary for linking to the DIEM-CGE macroeconomic model). Figure 2 shows the regional boundaries, developed from a combination of Integrated Planning Model (IPM) unit and transmission data, *Annual Energy Outlook* regional forecasts, and State Energy Data System (SEDS) state-level demand data. Several individual states are modeled due to their relative importance within broader regions or to limitations in electricity flows with surrounding states.

Figure 2. Regions in DIEM-Electricity



Load duration curves (LDC) show the amount of electricity demanded in each hour of the year (IPM 2010). The LDC can represent how various types of units are likely to be dispatched to meet demand in each hour of the year. The cheapest units with the lowest marginal generation costs are dispatched first, typically existing wind, solar, and hydroelectric. Following them are the baseload units, especially existing nuclear and coal with low fuel costs. Efficient natural gas combined cycle units enter next, depending on current gas prices, followed by less effective steam units, particularly those relying on relatively expensive types of petroleum. Finally, in a limited number of peak hours, combustion turbines that are cheap to construct but expensive to operate will enter the market.

Figure 3. Load duration curve and dispatch order (illustrative)



These hourly demand shapes are usually aggregated into a number of blocks representing seasons and times of day in electricity dispatch models such as DIEM-Electricity. The shapes can then be used to convert annual electricity demands from AEO forecasts into subcomponents that better capture the non-storage nature of electricity within a year. Together with forecasts of fuel prices and costs and characteristics of new units on the supply side of the model, the demand curves control how electricity markets behave.

Demand and price forecasts are normally fixed in electricity dispatch models, but DIEM-Electricity can also be linked to the DIEM-CGE macroeconomic model, which allows it to incorporate economy-wide responses to policies and also evaluate how annual demand levels and fuel prices may change under different policies.

STRUCTURE OF DIEM-ELECTRICITY MODEL

This section summarizes the equations that comprise the DIEM-Electricity model. Table 2 defines the sets and variables used, followed by the model functions.

Table 2. Elements of model

Labels	Definitions
Sets	
r (or rr)	Regions
p	Model plants
l	Load curve segments
f	Fuels
Variables and shadow prices	
CAP	Capacity
GEN	Generation
$TRS_{r,rr}$	Transmission from region r to region rr
INV	Investments in new capacity
RET	Retirements of old capacity
D^{ele}	Demand by region, load segment, and time period
p^{ele}	Price of wholesale electricity (average)
p^{whl}	Price of wholesale electricity (by segment of the load curve)
p^{cap}	Price of capacity
μ_p	Value of capacity scarcity for submarginal generators
Parameters	
p_f	Price of fuels
fom	Fixed O&M costs ($ per kW/year)
vom	Variable O&M costs ($ per MWh)
kap	Capital costs ($ per kW)
heatrate	Heat rate of plants (btu per kWh)
wheel	Wheeling charges (mills per kWh)
ctax	Carbon taxes ($ per $MMTCO_2$)
seq	Sequestration costs for captured CO_2 emissions ($ per $mtCO_2$)
CO2_coeff	Carbon coefficient (tons of CO_2 per MWh)
rsrv_coeff	Coefficient on contribution to meeting reserve margins
margin	Reserve margin by region (% over peak demand)

The objective function of the model (ignoring a possible linkage to DIEM-CGE that necessitate a different objective function—see Ross 2013) is to minimize the present value of system costs (C) of model plants for the U.S. electricity sector subject to meeting demand and other constraints, where the cost function is:

$$\mathbf{min} \sum_{r,t} \left(\frac{1}{1+\rho}\right)^t C_{r,t} =$$

$$\sum_{r,t} \left(\frac{1}{1+\rho}\right)^t \left[\sum_p \left(CAP_{r,p,t} \times fom_{r,p} + \sum_l GEN_{r,p,l,t} \times \left(vom_{r,p} + heatrate_{r,p} \times p_{f,t}\right)\right) + \right.$$

$$\sum_{rr.l} TRS_{r,rr,l,t} \times wheel + ctax_t \times \sum_{p,l} \left(GEN_{r,p,l,t} \times heatrate_{r,p} \times CO2\_coeff_p\right) + \ seq_p \times$$

$$\sum_{p\in ccsp,l}\left(GEN_{r,p.l,t} \times heatrate_{r,p} \times CO2\_coeff_p\right)] \ + \sum_{r,t}\left(\frac{1}{1+\rho}\right)^t \left[\sum_{p\in new}\left(INV_{r,p,t} \times kap_{r,p,t}\right)\right] \quad (1)$$

The demand constraint says that generation in each segment of the load curve plus net imports (including transmission losses) must be greater than (or equal to) demand:

$$\sum_p GEN_{r,p,l,t} + \sum_{rr}\left(TRS_{r,rr,l,t} \times \left(1 - loss_{r,rr}\right)\right) - \sum_{rr} TRS_{rr,r,l,t} \ \geq \ D^{ele}_{r,l,t} \quad \perp \ p^{whl}_{r,l,t} \quad (2)$$

where the wholesale price of electricity in each load segment, p^{whl}, is the complementary variable to the demand constraint.

For reporting and linkage to the DIEM-CGE model, a weighted average wholesale price, p^{ele}, is calculated across load segments:

$$\frac{1}{\sum_{p,l} GEN_{r,p,l,t}} \times \sum_{p,l}\left(GEN_{r,p,l,t} \times p^{whl}_{r,l,t}\right) \ = \ p^{ele}_{r,t} \quad (3)$$

The reserve margin constraint states that available capacity, weighted by its contribution to reserve margins, must meet or exceed peak electricity demands plus the reserve margin:

$$\sum_p\left(CAP_{r,p,t} \times rsrv\_coeff_{r,p}\right) \ \geq \ \left(D^{ele}_{r,peak,t} \times (1 + margin_r\right) \ \perp \ p^{cap}_{r,t} \quad (4)$$

where the value of capacity, p^{cap}, is the complementary variable to the reserve margin.

Each generating plant can provide an amount of electricity up to its capacity, factoring in its availability in a load segment (there are also minimum generation levels for some types of plants):

$$GEN_{r,p,l,t} \ \leq \ CAP_{r,p,t} \times Plant\ Availability_{r,p,l,t} \ \perp \ \mu_{r,p.l,t} \quad (5)$$

where the scarcity rents of submarginal generating plants, μ_p, is the complementary variable on the capacity constraint. (This scarcity rent is a factor in the linkage to DIEM-CGE.)

Ignoring constraints on total investments and total new capacity by type, capacity of each type of plant is a function of past capacity plus investments and retirements:

$$CAP_{r,p,t} \ = \ CAP_{r,p,t-1} \ + \ INV_{r,p,t} \ - \ RET_{r,p,t} \quad (6)$$

For any policies with a cap on emissions (in this case, a national CO_2 cap), there is an additional constraint (ignoring banking and borrowing of emissions allowances):

$$\sum_{r,p.l,t}\left(GEN_{r,p,l,t} \times heatrate_{r,p} \times CO2\_coeff_p\right) \ \leq \ Emissions\ Cap_t \ \perp \ p^{carb}_t \quad (7)$$

where the complementary variable to the emissions constraint, p^{carb}, is the allowance price of CO_2.

Other policies can put lower bounds in MWh on particular types of generation such as a clean energy standard (CES):

$$\sum_{r,p\in CES,l,t} GEN_{r,p.l,t} \ \geq \ CES_t \quad \perp \ p^{CES}_t \quad (8)$$

where the complementary variable to the policy constraint, p^{CES}, is the shadow value of generating a MWh of clean electricity.

Additional constraints handle issues such as limits on transmission flows among regions:

$$TRS_{r,rr,l,t} \ \leq \ TRS\ Limit_{r,rr,t} \quad (9)$$

Particular resources such as wind, solar, landfill gas, geothermal, and biomass fuels also have limited availability (wind is shown here):

$$CAP_{r,wndp,t} \leq Wind\ Availability_r \tag{10}$$

SUPPLY SIDE OF THE DIEM-ELECTRICITY MODEL

Electricity is supplied in DIEM-Electricity by a combination of existing and endogenously constructed new plants. Data on existing plants come from the NEEDS database v.4.10 (IPM 2010), which characterizes more than 15,000 boiler-generator combinations across all configurations of plant type, fuel source, location, and installed equipment. To maintain computational tractability, these existing units are aggregated into model plants on the basis of common characteristics. Criteria potentially considered in these aggregations include

- Plant type
- Plant location (region and state)
- Heat rate (btu per kWh)
- Size
- Age
- Existing equipment (FGD, NOx, Hg, and particulate matter retrofits)

Depending on the topic of interest, the existing units may be grouped into a few hundred or a few thousand model plants. Typically, non-fossil units are more highly aggregated than conventional fossil units, because the former are less likely to reduce operation in response to the types of environmental policies usually explored by DIEM-Electricity.

Existing model plants include the following types:

- Pulverized coal
- Integrated gasification combined cycle (IGCC)—coal
- Natural gas combined cycle
- Natural gas combustion turbines (NGCC) (gas- and oil-fired)
- Steam (gas- and oil-fired)
- Nuclear
- Hydroelectric
- Geothermal
- Biomass
- Municipal solid waste
- Landfill gas
- Solar
- Wind
- Pump storage

The amount of electricity supplied by existing (and new) model plants depends on the number of hours that they are typically available during the year to generate electricity. In DIEM-Electricity, "availability factors" are used to characterize how much plants can feasibly operate, taking into account scheduled maintenance and forced outages. Table 3 shows availability for existing and new dispatchable units; availability for non-dispatchable units is shown in tables 10–12 and can vary by type of unit, location, season, and time of day. Availability for existing fossil units can vary and comes from the IPM NEEDS database.

Table 3. Unit availability

Unit Type	Availability
Pulverized coal (new)	85%
IGCC (new)	85%
NGCC	85%
Natural gas combustion turbine	92%
Steam oil/gas	87%
Nuclear (new units)	90%
Biomass	83%
Landfill gas	83%
Geothermal	~87%

Note: Author's calculations based on IPM (2010).

There are also minimum generation levels for coal and steam oil/gas units based on IPM (2010); these units are required to produce a minimum amount of electricity during baseload periods for each hour they run during peak periods. These turndown assumptions reflect the fact that coal units are not quick-start units.

The model includes operating costs of existing units in its cost minimization decisions. Fixed O&M costs are required on an annual basis to maintain a unit, whereas variable O&M costs depend on the number of hours a unit is dispatched during a year. Neither can be avoided if a unit is to run during any load segment of the year. Fixed operating costs for most existing fossil-fueled units are a function of age and existing equipment, as shown by the average ranges in Table 4. Variable O&M costs are also a function of existing equipment for some units.

Variable costs can be avoided by ceasing generation during a particular load segment of the year, and fixed costs can be avoided through retirement decisions. (Note that retired units do not count toward system reliability requirements.)

Table 4. Operating costs of existing units

Unit Type	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)
Pulverized coal	$34.2–$65.2	$1.95–$6.94
NGCC	$13.1	$13.12
Natural gas combustion turbine	$3.9–$9.2	$3.85–$9.16
Steam oil/gas	$19.2–$30.5	$3.83–$4.38
Hydroelectric	$14.9	$6.93
Biomass	$20.9	$7.27
Landfill gas	$24.6	$9.15
Geothermal	$22.5	$8.64
Solar thermal	$23.5	$2.89
Solar PV	$17.8	$2.18
Wind	$19.1	$3.31
Pump storage	$20.1	$8.71

Note: Author's calculations based on IPM (2010). Costs of existing fossil generators can vary with unit aggregation, age, and existing equipment (average range is shown).

The model has the ability to build new units in response to demand growth and changes in the industry's cost structure resulting from environmental policies. Table 5 presents data on the costs and performance characteristics of the types of new units considered in DIEM-Electricity. These data are from the *Annual Energy Outlook* (AEO), where operating costs are constant across the lifetime of the new unit and capital costs decrease depending on the year of installation. Declines in capital costs are generally linear between the overnight costs shown for 2012 and the final year in which capital costs improve (2035). These declines are based on improvements shown in the AEO 2012 Reference Case. The table also shows data from the National Renewable Energy Laboratory (NREL) on the additional costs to connect new units to the grid. In addition to the operating costs shown in Table 5, the model assumes a carbon capture, transport, and storage cost of \$15/mtCO_2 based on EPA climate policy analyses, assuming a 90% removal rate for the carbon capture and storage (CCS) units.

These data on capital costs are combined with information on regional capital costs from the *Annual Energy Outlook* to get region-specific construction costs. The model also uses data on wind capital cost multipliers from IPM (2010) to convert wind capital costs into costs by wind cost class and to distinguish between offshore shallow and deep wind applications, shown in Table 7.

Like the U.S. Environmental Protection Agency (EPA) IPM and NREL ReEDS models, DIEM-Electricity adjusts the overnight capital costs shown in Table 6 to account for real-world considerations affecting investment decisions. Among these are the time value of money, types of financing options, tax considerations, and construction time for different types of units. These considerations are factored into unit-specific discount rates, which determine a weighted average cost of capital that can then be used to calculate a capital charge rate that converts the overnight capital costs into a stream of levelized annual payments necessary to recover the investment costs.

In these calculations, the weighted average cost of capital (WACC) is as follows:

$$WACC_{nominal} = E \times R_e + D \times R_d \times (1 - T)$$

$$WACC_{real} = \frac{1 + WACC_{nominal}}{1 + i} - 1$$

where:

E = equity fraction
R_e = return on equity
D = debt fraction
R_d = return on debt
T = tax rate
i = inflation rate

The capital charge rate based on the weighted cost of capital, where u is the book life of the unit, is then:

$$CCR_{real} = \left(\sum_{t=1}^{u}(1 + WACC_{real})^{-t}\right)^{-1} = \frac{WACC_{real}}{1 - (1 + WACC_{real})^{-u}}$$

The model's standard approach is to use capital charge rates and book lives based on IPM (2010).

Table 5. Technology rates and book lives

Technology	Capital Charge Rate	Discount Rate	Book Life
Scrubbed coal	14.1%	7.8%	40
IGCC	14.1%	7.8%	40
IGCC with CCS	11.1%	5.5%	40
NGCC	12.1%	6.2%	30
NGCC with CCS	12.1%	6.2%	30
Natural gas combustion turbine	12.9%	6.9%	30
Fuel cells	12.2%	6.2%	20
Nuclear	10.8%	5.5%	40
Biomass	11.1%	6.2%	40
Geothermal	12.2%	6.2%	20
Landfill gas	12.2%	6.2%	20
Wind	12.2%	6.2%	20
Solar	12.2%	6.2%	20

Note: Author's calculations based on IPM (2010).

Note that these calculations ignore any American Recovery and Reinvestment Act (ARRA) loan guarantees for renewable generation and nuclear production tax credits provided in the Energy Policy Act of 2005. They also include an assumption used in the *Annual Energy Outlook* that increases the cost of capital for fossil generation by 3% to account for uncertainty in such investments related to the possibility of future climate policies.

Table 6. New unit costs and characteristics

Technology	Total Overnight Cost in 2012 (2011 $/kW)	Overnight Costs in 2035 (2011 $/kW)	Variable O&M (2011 mills/kWh)	Fixed O&M ($2011/kW)	Heatrate in 2010 (Btu/kWh)	nth-of-a-kind Heatrate (Btu/kWh)	NREL Grid Connect Costs (2009 $/kW)
Scrubbed coal – New	$2,883	$2,182	$4.39	$30.64	8,800	8,740	$227
Integrated coal-gasification comb cycle (IGCC)	$3,718	$2,647	$7.09	$50.49	8,700	7,450	$227
IGCC with carbon capture & sequestration (CCS)	$5,138	$3,261	$4.37	$65.31	12,000	9,316	$227
NGCC	$1,006	$725	$3.21	$15.10	6,430	6,333	$114
NGCC with CCS	$2,059	$1,261	$6.66	$31.29	7,525	7,493	$114
Natural gas combustion turbine	$664	$462	$10.19	$6.92	9,750	8,550	$114
Fuel cells	$6,982	$3,906	$0.00	$357.47	9,500	6,960	$114
Nuclear	$5,429	$3,535	$2.10	$91.65	10,452	10,452	$227
Biomass	$4,041	$2,925	$5.17	$103.79	13,500	13,500	$114
Geothermal	$2,567	$2,633	$0.00	$110.94	9,756	9,756	$227
Landfill gas	$8,408	$6,362	$8.51	$381.74	13,648	13,648	$114
Wind	$2,175	$1,752	$0.00	$38.86	9,756	9,756	$114
Wind offshore	$6,121	$3,969	$0.00	$72.71	9,756	9,756	$227
Solar thermal	$4,979	$2,157	$0.00	$66.09	9,756	9,756	$114
Solar photovoltaic	$3,805	$2,022	$0.00	$21.37	9,756	9,756	$0

Note: Author's calculations based on Annual Energy Outlook and Short et al (2011). Costs are shown in the year of the original sources but are converted into 2010 dollars prior to use in the model.

Table 7. Wind capital cost multipliers

Wind Cost Class	Capital Cost Multiplier
1	1
2	1.2 (1.35 offshore)
3	1.5
4	2.5
Deep Offshore	1.5 x Offshore from *AEO*

Note: Author's calculations based on IPM (2010).

In addition to local generation a region can import electricity to meet demand. Table 8 below shows constraints on the flow of electricity among regions that reflect the capacity of the grid to handle these transfers. The model currently does not allow new transmission lines to be constructed. There is also a wheeling charge of 2.9 mills per kWh on interregional flows.

Table 8. Transmission limits among regions (GW)

Importing/Exporting Region	New England	New York	Middle Atlantic	East North Central	West North Central	South Atlantic	Florida	East South Central	West South Central	Texas	Upper Mountain States	Arizona, New Mexico, Colorado	Pacific	California
New England		1.6												
New York	1.89		3.12			0.26								
Middle Atlantic		3.19		7.98	0.19	8.65		0.59						
East North Central			8.75		4.78	11.73		3.82	1.36	0.12	0.02	0.01		
West North Central			0.17	4.88		0.08	0.01	1.88	5.6	0.67	0.27	0.25		
South Atlantic		0.24	7.81	13.22	0.1		1.89	8.34	1.09	0.1				
Florida					0.01	1.03		1.11	0.09	0.01				
East South Central			0.88	6.04	1.17	3.92	1.8		3.58	0.43	0	0.01		
West South Central				0.43	2.47	0.82	0.07	2.93		1.7	0	0.35		0.01
Texas				0.04	0.59	0.07	0.01	0.63	3.25		0.07	0.13		0.05
Upper Mountain States				0.02	0.22			0	0.01	0.07		5.58	1.84	7.49
Arizona, New Mexico, Colorado				0.01	0.26			0.03	0.42	0.12	5.46			3.5
Pacific											1.38			6.51
California									0.01	0.05	6.93	3.5	6.22	

Note: Author's calculations based on IPM (2010).

Table 9 shows the availability factors for existing nuclear units from the IPM NEEDS database. These factors show some variation by season of the year.

Table 9. Availability of existing nuclear units by season and time of day

	Summer				Winter				Spring/Fall			
	Morning	After-noon	Evening	Night	Morning	After-noon	Evening	Night	Morning	After-noon	Evening	Night
New England	95%	95%	95%	95%	88%	88%	88%	88%	91%	91%	91%	91%
New York	96%	96%	96%	96%	89%	89%	89%	89%	92%	92%	92%	92%
Middle Atlantic	95%	95%	95%	95%	89%	89%	89%	89%	92%	92%	92%	92%
East North Central	95%	95%	95%	95%	89%	89%	89%	89%	92%	92%	92%	92%
West North Central	94%	94%	94%	94%	87%	87%	87%	87%	91%	91%	91%	91%
South Atlantic	94%	94%	94%	94%	88%	88%	88%	88%	91%	91%	91%	91%
Florida	94%	94%	94%	94%	88%	88%	88%	88%	91%	91%	91%	91%
East South Central	90%	90%	90%	90%	91%	91%	91%	91%	90%	90%	90%	90%
West South Central	94%	94%	94%	94%	88%	88%	88%	88%	91%	91%	91%	91%
Texas	95%	95%	95%	95%	88%	88%	88%	88%	91%	91%	91%	91%
AZ, NM, CO	94%	94%	94%	94%	87%	87%	87%	87%	91%	91%	91%	91%
Pacific	87%	87%	87%	87%	92%	92%	92%	92%	90%	90%	90%	90%
California	94%	94%	94%	94%	87%	87%	87%	87%	91%	91%	91%	91%

Note: Author's calculations based on IPM (2010).

Similarly, tables 10–12 show the availability factors of non-dispatchable units (hydro, solar, and wind) by season and time of day.

Table 10. Solar availability by season and time of day

Region	Summer				Winter				Spring/Fall			
	Morning	After-noon	Evening	Night	Morning	After-noon	Evening	Night	Morning	After-noon	Evening	Night
Solar PV												
New England	34%	47%	13%	1%	29%	40%	11%	2%	32%	44%	12%	1%
New York	34%	47%	13%	1%	26%	36%	10%	2%	30%	42%	11%	1%
Middle Atlantic	34%	47%	13%	1%	28%	38%	11%	2%	31%	43%	12%	1%
East North Central	36%	49%	13%	1%	28%	38%	11%	2%	32%	44%	12%	1%
West North Central	36%	50%	13%	1%	32%	44%	13%	2%	34%	47%	13%	2%
South Atlantic	35%	49%	13%	1%	30%	41%	12%	2%	33%	45%	12%	1%
Florida	36%	49%	13%	1%	35%	49%	14%	2%	35%	49%	13%	2%
East South Central	36%	49%	13%	1%	29%	40%	11%	2%	32%	45%	12%	1%
West South Central	36%	50%	13%	1%	33%	45%	13%	2%	35%	48%	13%	2%
Texas	37%	52%	14%	1%	34%	47%	13%	2%	35%	49%	13%	2%
Upper Mountain States	41%	57%	15%	1%	33%	45%	13%	2%	37%	51%	14%	2%
AZ, NM, CO	43%	60%	16%	1%	38%	53%	15%	2%	41%	56%	16%	2%
Pacific	39%	54%	14%	1%	28%	38%	11%	2%	33%	46%	13%	2%
California	43%	60%	16%	1%	35%	49%	14%	2%	39%	54%	15%	2%
Solar Thermal												
West North Central	48%	58%	32%	9%	29%	36%	17%	4%	38%	47%	24%	6%
West South Central	49%	59%	32%	9%	31%	39%	19%	5%	40%	49%	25%	7%
Texas	49%	59%	32%	9%	37%	46%	22%	5%	43%	53%	27%	7%
Upper Mountain States	58%	70%	38%	11%	38%	47%	23%	5%	48%	59%	30%	8%
AZ, NM, CO	59%	71%	39%	11%	43%	54%	26%	6%	51%	62%	32%	9%
Pacific	57%	69%	38%	11%	33%	41%	20%	5%	45%	55%	28%	8%
California	71%	86%	47%	13%	46%	57%	27%	7%	59%	72%	37%	10%

Note: Author's calculations based on IPM (2010).

Table 11. Wind availability by season and time of day (wind class 3 shown)

	Summer				Winter				Spring/Fall			
Region	**Morning**	**After-noon**	**Evening**	**Night**	**Morning**	**After-noon**	**Evening**	**Night**	**Morning**	**After-noon**	**Evening**	**Night**
New England	23%	27%	27%	26%	16%	16%	18%	19%	20%	22%	22%	22%
New York	28%	33%	32%	31%	20%	19%	21%	23%	24%	26%	27%	27%
Middle Atlantic	28%	33%	32%	31%	20%	19%	21%	23%	24%	26%	27%	27%
East North Central	29%	34%	33%	32%	20%	20%	22%	23%	25%	27%	28%	28%
West North Central	31%	36%	35%	34%	22%	21%	24%	25%	26%	29%	29%	30%
South Atlantic	35%	42%	40%	39%	25%	24%	27%	28%	30%	33%	34%	34%
East South Central	39%	46%	44%	44%	27%	27%	30%	31%	33%	37%	37%	38%
West South Central	37%	44%	42%	42%	26%	26%	29%	30%	32%	35%	36%	36%
Texas	29%	35%	34%	33%	21%	20%	23%	24%	25%	28%	28%	28%
Upper Mountain States	38%	46%	44%	43%	27%	27%	30%	31%	33%	36%	37%	37%
AZ, NM, CO	34%	40%	39%	38%	24%	24%	26%	28%	29%	32%	33%	33%
Pacific	38%	46%	44%	43%	27%	27%	30%	31%	33%	36%	37%	37%
California	22%	26%	25%	24%	15%	15%	17%	18%	18%	20%	21%	21%

Note: Author's calculations based on IPM (2010).

Table 12. Hydroelectric availability by season and time of day

	Summer				Winter				Spring/Fall			
	Morning	After-noon	Evening	Night	Morning	After-noon	Evening	Night	Morning	After-noon	Evening	Night
New England	41%	41%	41%	41%	45%	45%	45%	45%	43%	43%	43%	43%
New York	62%	62%	62%	62%	66%	66%	66%	66%	64%	64%	64%	64%
Middle Atlantic	34%	34%	34%	34%	47%	47%	47%	47%	41%	41%	41%	41%
East North Central	48%	48%	48%	48%	43%	43%	43%	43%	46%	46%	46%	46%
West North Central	41%	41%	41%	41%	30%	30%	30%	30%	36%	36%	36%	36%
South Atlantic	23%	23%	23%	23%	25%	25%	25%	25%	24%	24%	24%	24%
Florida	47%	47%	47%	47%	48%	48%	48%	48%	48%	48%	48%	48%
East South Central	37%	37%	37%	37%	43%	43%	43%	43%	40%	40%	40%	40%
West South Central	29%	29%	29%	29%	25%	25%	25%	25%	27%	27%	27%	27%
Texas	20%	20%	20%	20%	14%	14%	14%	14%	17%	17%	17%	17%
Upper Mountain States	40%	40%	40%	40%	25%	25%	25%	25%	33%	33%	33%	33%
AZ, NM, CO	32%	32%	32%	32%	25%	25%	25%	25%	29%	29%	29%	29%
Pacific	44%	44%	44%	44%	41%	41%	41%	41%	42%	42%	42%	42%
California	50%	50%	50%	50%	37%	37%	37%	37%	44%	44%	44%	44%

There are twenty possible types of onshore wind resources across wind classes and cost classes in each region of the model. The table below gives these wind resources by wind class, cost class, and region.

Table 13. Wind resources (GW)

	Wind Class	Cost Class	New England	New York	Middle Atlantic	East North Central	West North Central	South Atlantic	Florida	East South Central	West South Central	Texas	Upper Mountain States	AZ, NM, CO	Pacific	Cali-fornia
Onshore	3	1	1.8	0.1	1.1	16.2	0.0	0.3		0.2	0.1	3.2	1.9	2.0	0.2	3.0
		2		3.4	1.1	22.9		0.8			0.0			1.7	0.9	
		3		4.5	2.7	8.3		4.8			0.1	1.2		0.0	0.4	
		4	9.1	4.7	3.7	532.5	2,476.0	4.3		0.9	452.9	322.0	633.3	535.6	74.3	26.7
	4	1	0.7	0.1	0.2	0.1	1.9	0.1		0.0	2.9	9.9	1.9	3.3	0.1	1.9
		2	1.1	0.5		0.9	9.7	0.5		0.1	11.4	32.7	6.2	5.1	0.3	2.5
		3			0.6	1.1	200.4			0.2	44.4	2.8	7.7	8.5	0.2	2.9
		4	2.0	1.0	0.6	1.6	1,174.0	0.7		0.2	349.7	51.4	237.1	250.2	15.5	4.1
	5	1	0.4		0.1		2.1	0.1		0.0	2.7	0.4	0.4	2.6	0.0	0.5
		2	0.4	0.2		0.0	22.1				13.2	1.4	1.1	9.1	0.1	1.2
		3			0.2		68.4	0.2		0.1		0.9	3.6	17.5	0.1	1.4
		4	1.0	0.2	0.2	0.1	156.9	0.2		0.1	21.2	1.5	50.6	61.3	3.5	1.6
	6	1	0.0				1.3	0.1		0.0	0.0	0.2	0.1	3.4	0.0	0.4
		2	0.4		0.0		2.0				0.1		1.2	8.4	0.1	
		3	0.5	0.1			1.4	0.2		0.0	0.1	0.5	3.8	11.7	0.1	1.2
		4	0.4	0.1	0.0		4.5	0.2		0.0	0.2	0.6	17.7	15.3	1.5	1.3
	7	1	0.1					0.0				0.0	0.2	0.6	0.0	0.1
		2						0.0		0.0			1.5	6.3	0.1	0.4
		3											0.8	2.3	0.1	0.2
		4	0.5	0.0				0.1		0.0	0.0	0.0	1.8	6.9	0.2	0.6
Offshore Shallow	3	1	2.3	1.7	2.9	5.7	0.4	17.8	43.3		43.0	14.4			0.7	0.8
		2	4.7	3.4	5.8	11.4	0.8	35.5	86.6		86.0	28.7			1.4	1.6
		4	4.7	3.4	5.8	11.4	0.8	35.5	86.6		86.0	28.7			1.4	1.6
	4	1	3.1	2.7	8.3	10.0	1.0	20.6	6.1		0.7	15.2			1.7	0.4
		2	6.3	5.4	16.6	20.1	1.9	41.2	12.2		1.4	30.4			3.3	0.8
		4	6.3	5.4	16.6	20.1	1.9	41.2	12.2		1.4	30.4			3.3	0.8
	5	1	3.0	2.5	10.2	12.9	0.3	17.9				4.5			1.3	0.2
		2	6.0	5.0	20.3	25.9	0.7	35.8				8.9			2.6	0.4
		4	6.0	5.0	20.3	25.9	0.7	35.8				8.9			2.6	0.4
	6	1	6.2	0.5	5.1	4.5	0.0	6.9							0.2	0.1
		2	12.3	1.1	10.3	9.1	0.0	13.7							0.4	0.3
		4	12.3	1.1	10.3	9.1	0.0	13.7							0.4	0.3
	7	1	0.3			0.0									0.1	0.0
		2	0.7			0.0									0.2	0.0
		4	0.7			0.0									0.2	0.0
Offshore Deep	3	1	0.1	0.1	0.0	0.6	0.4	8.8	28.0		13.5				0.2	14.8
		2	0.3	0.1	0.0	1.2	0.7	17.5	56.0		26.9				0.5	29.5
		4	0.3	0.1	0.0	1.2	0.7	17.5	56.0		26.9				0.5	29.5
	4	1	1.8	2.1	0.2	5.3	4.9	15.1	53.9		10.7	10.5			0.8	35.1
		2	3.5	4.1	0.3	10.5	9.8	30.1	107.7		21.5	21.0			1.6	70.2
		4	3.5	4.1	0.3	10.5	9.8	30.1	107.7		21.5	21.0			1.6	70.2
	5	1	3.7	6.4	1.6	18.0	3.3	8.9	1.1			6.5			12.5	24.3
		2	7.4	12.8	3.2	36.1	6.6	17.7	2.2			13.1			25.0	48.7
		4	7.4	12.8	3.2	36.1	6.6	17.7	2.2			13.1			25.0	48.7
	6	1	59.3	16.1	22.5	73.9	1.5	39.8							34.8	31.4
		2	118.7	32.1	45.0	147.8	3.1	79.7							69.6	62.8
		4	118.7	32.1	45.0	147.8	3.1	79.7							69.6	62.8
	7	1	1.8	0.0		0.0									25.7	19.5
		2	3.5	0.0		0.1									51.5	39.0

Note: Author's calculations based on IPM (2010).

The model includes estimates of landfill gas resources, distinguishing three categories with different rates of production and capital costs. Capital costs are: $8,230/kW for the "High" category, $10,370/kW for the "Low" category, and $15,966/kW for the "Very Low" category.

Table 14. Landfill gas resources (GW)

	High	Low	Very Low
New England	0.062	0.006	0.051
New York	0.054	0.027	0.142
Middle Atlantic	0.093	0.022	0.311
East North Central	0.083	0.092	0.495
West North Central	0.043	0.022	0.15
South Atlantic	0.068	0.022	0.447
East South Central	0.072	0.03	0.539
West South Central	0.005		0.185
Pacific	0.027	0.058	0.276
California	0.131	0.25	0.749

Note: Author's calculations based on IPM (2010) and the Annual Energy Outlook.

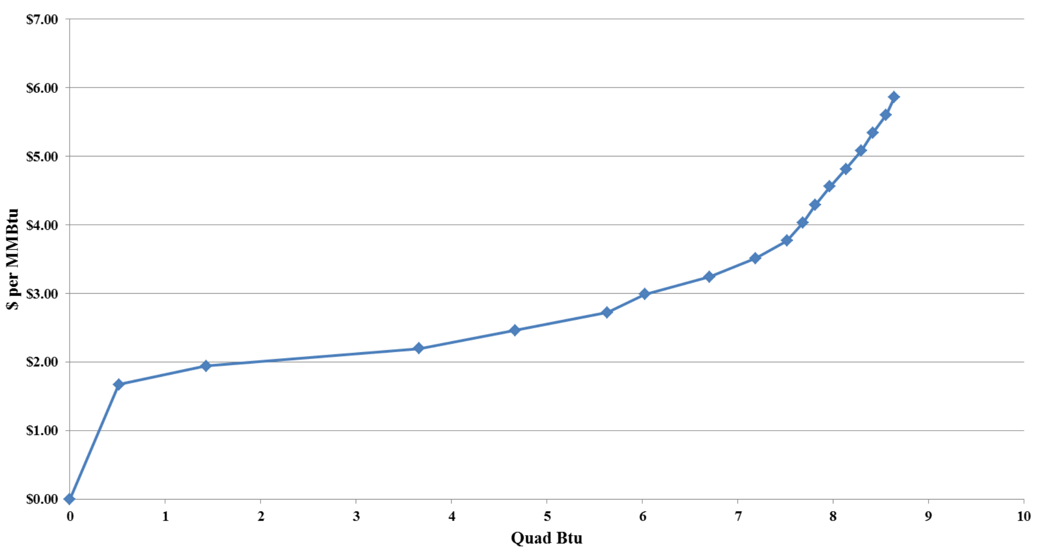
Geothermal generation is also controlled by estimates of availability at particular costs.

Table 15. Geothermal costs and resource availability

	Class									
	1	2	3	4	5	6	7	8	9	10
Capital cost ($/kW)										
Upper mountain states	$6,255	$8,337	$9,776	$11,465	$20,674	$4,523	$5,380	$3,428	$4,594	$8,210
AZ, NM, CO	$4,088	$4,675	$5,650	$7,744	$9,199					
Pacific	$3,890	$4,782	$5,211	$5,625						
California	$1,624	$2,873	$4,214	$4,957	$5,679	$6,817				
GW available										
Upper mountain states	0.01	0.02	0.10	1.17	3.00	0.14	0.07	0.01	0.03	0.01
AZ, NM, CO	1.47	0.20	0.32	0.29	0.01					
Pacific	0.27	0.04	0.42	0.61						
California	0.58	0.01	0.08	0.07	0.05	0.01				

Biomass generation is limited by the regional cost and availability of the biomass fuel. Figure 4 below illustrates at a national level the available biomass supplies and costs in the year 2020.

Figure 4. U.S. aggregate biomass supply curve for 2020



Unlike the fuel supply curve for biomass and the limits on resource availability for wind, geothermal, and landfill gas, the expansion of other types of generation is less constrained by increasing costs. Nuclear fuel costs are $0.75–$1.00 per MMBtu and are unaffected by any increased demand from new nuclear units. Coal and natural gas fuel prices are initially from the *Annual Energy Outlook*. If DIEM-Electricity is running as a stand-alone model, these fuel supplies and prices are also unaffected by any increases in demand. This remains an area for future work; the goal is to incorporate graded coal resources with increasing costs to allow investigation of criteria pollutant policies affected by the characteristics of different coal ranks. The plan is to also include an endogenous supply curve for natural gas, because gas generation may represent a feasible response to environmental and climate policies. (If DIEM-Electricity is linked to DIEM-CGE, the macroeconomic model provides coal and gas prices that are determined by supply-demand conditions in the United States and interactions with climate change policies.)

To address the absence of fuel-price constraints on the desire to expand fossil and nuclear generation, and more importantly, to address potential limits on the ability of construction firms to build new generating units, the model incorporates assumptions and results from both the IPM model and the *Annual Energy Outlook* (specifically, the *AEO* side cases related to carbon taxes) to establish limits on the deployment of new capacity by type and installation year. The IPM (2010) assumptions are based on an EPA analysis of the capability of engineering and construction firms to build new large-scale power projects in the United States, particularly those related to nuclear and CCS units for which IPM specifies both a joint limit on total new capacity of nuclear and CCS (with a tradeoff between the two types of installations) and a limit on how much new nuclear can be constructed every five years. Limits based on an examination of the maximum construction rates in the *AEO* side case related to a $25/ton carbon tax growing at 5% are applied to other types of new units, as shown in Table 16 (these are feasible upper bounds, not construction requirements; whether units are built depends on their economics and electricity demands).

Table 16. Limits on new capacity deployment (total and incremental investments): GW

		2015	2020	2025	2030	2035	2040	2045	2050
Joint total capacity [a]	Nuclear (new)		7.5	18.5	29.4	57.9	86.4	156.2	225.9
	CCS		9.8	24.0	38.2	75.3	112.4	203.0	293.7
Total new capacity	Nuclear + Coal + NGCC [f]	26.1	67.2	79.5	107.9	141.8	200.5	239.4	322.5
	Solar Thermal [b]		0.7	1.2	1.9	3.1	5.0	8.1	13.0
	Solar PV [b]		0.4	17.1	31.3	44.6	110.2	242.5	310.2
New investments by type (per 5-year period)	Nuclear [c]		7.5	9.8	19.6	31.4	55.0	67.8	101.7
	Pulverized coal [d]		7.5	9.8	19.6	31.4	55.0	67.8	101.7
	IGCC [d]		7.5	9.8	19.6	31.4	55.0	67.8	101.7
	IGCC with CCS [d]		7.5	9.8	19.6	31.4	55.0	67.8	101.7
	NGCC with CCS [d]		7.5	9.8	19.6	31.4	55.0	67.8	101.7
	NGCC [e]	26.1	52.2	59.9	68.7	78.9	90.5	103.9	119.2
	Solar thermal [e]	46.2	49.0	51.8	54.6	57.6	60.7	63.9	67.4
	Solar PV [e]	46.2	49.0	51.8	54.6	57.6	60.7	63.9	67.4

[a] IPM (2010) limit on combined construction of nuclear and CCS units. Can construct the upper bound for either type or a linear combination between the two end points.
[b] In the absence of an explicit solar resource in the model, an upper bound is established on the basis of maximum total construction in the *AEO* side cases.
[c] IPM limit on new construction of nuclear units per 5-year period (assuming construction begins by 2020).
[d] The IPM limit on nuclear is also applied to pulverized coal, IGCC, IGCC with CCS, and NGCC with CCS. These 5-year limits do not override the joint total constraint on nuclear plus CCS.
[e] Upper bounds on NGCC, solar thermal, and solar PV construction are based on the *AEO* side cases.
[f] Joint upper bound on nuclear plus all types of coal plus NGCC, based on other limits shown.

DEMAND SIDE OF THE DIEM-ELECTRICITY MODEL

Annual demands by region are defined by combining the EIAs SEDS data for state-level electricity demand and prices (EIA 2012) with the nine census region forecasts from the *Annual Energy Outlook*. Annual demand forecasts after 2040 are extended along growth trends on the basis of population growth, labor productivity, and estimated improvements in energy efficiency (see Ross 2013). Hourly demands within a year are estimated using hourly load curves from IPM (2010). These hourly data convert the annual demand into 13 demand segments by season of the year and time of day.

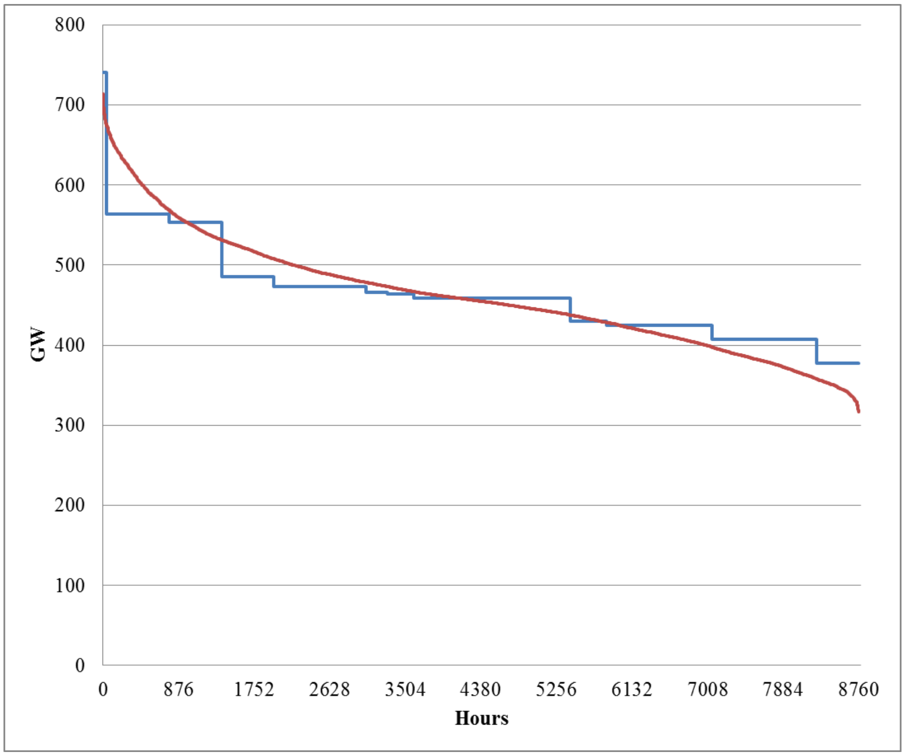
Table 17 shows these seasons and times of day for 12 of the 13 segments in the model's load curve. There is also a peak segment, defined as the 40 highest demand hours across the year (which are differentiated at the regional level). The seasons and time-of-day categories are generally similar to those of the NREL ReEDS model (Short et al. 2009), with the exception of the aggregated spring/fall season and the end point of the afternoon hours.

Table 17. Load segments by season and time of day

Season	Time of Day	Hours of Day	Annual Hours
Summer (May–September)	Morning	6am to 1pm	1071
	Afternoon	1pm to 6pm	725
	Evening	6pm to 10pm	612
	Night	10pm to 6am	1224
Spring/Fall (October, April)	Morning	6am to 1pm	427
	Afternoon	1pm to 6pm	305
	Evening	6pm to 10pm	244
	Night	10pm to 6am	488
Winter (November–March)	Morning	6am to 1pm	1057
	Afternoon	1pm to 6pm	755
	Evening	6pm to 10pm	604
	Night	10pm to 6am	1208
Peak	Highest Summer Afternoon Hours		40

Figure 5 shows the hourly demand estimates across the United States from IPM (2010) as the smooth curve. Figure 5 also shows how this curve is then represented in the model as the 13 load segments described in Table 17. The model incorporates this type of load curve with these segments for each of the 14 regions in the model, where the annual forecasted demands are converted into these segments within each time period.

Figure 5. Load duration curve for United States (illustrative for 2010)



Peak demands come from the hourly load data in IPM (2010) and are assumed to grow with the annual demand forecasts from the *Annual Energy Outlook*. Table 18 shows the nonconcurrent peak demand levels by region. These peaks interact with regional reserve margin requirements to ensure system reliability.

Table 18. Peak demands by region (2010)

Region	GW
New England	23.6
New York	30.7
Middle Atlantic	40.0
East North Central	90.6
West North Central	47.4
South Atlantic	113.0
Florida	44.2
East South Central	40.6
West South Central	44.0
Texas	64.7
Upper Mountain States	14.5
Arizona, New Mexico, Colorado	33.5
Pacific	25.7
California	60.2

Note: Author's calculations based on IPM (2010).

Reserve margins represent a demand for extra capacity, over and above the maximum demand level at any hour of a year. Typically, reserve margins are around 15% above this peak hourly demand. This constraint implies a price for capacity in the model. This excess capacity could be traded among regions, although this possibility is not currently included in the model.

Table 19. Reserve margins by region

Region	Margin
New England	16.0%
New York	16.5%
Middle Atlantic	15.0%
East North Central	15.2%
West North Central	14.4%
South Atlantic	15.0%
Florida	15.0%
East South Central	13.9%
West South Central	14.3%
Texas	12.9%
Upper Mountain States	13.3%
Arizona, New Mexico, Colorado	15.1%
Pacific	10.8%
California	16.7%

Note: Author's calculations based on IPM (2010).

Baseload units such as coal and nuclear, along with on-demand units such as combined cycle and steam, contribute a full share of their available gigawatts to meeting reserve margins. However, non-dispatchable units such as wind and solar are less helpful in meeting reliability requirements, because they can't easily adjust the time of day at which they provide capacity to the system. As a result, their capacity receives less than a full share in meeting reserve margins. Table 20 shows these shares as a percentage of their total capacity.

Table 20. Non-dispatchable units contributions to meeting reserve margins

Region	Solar Thermal	Solar PV	Wind Class: Onshore 3	Onshore 4	Onshore 5	Onshore 6	Onshore 7	Offshore Shallow 3	Offshore Shallow 4	Offshore Shallow 5	Offshore Shallow 6	Offshore Shallow 7	Offshore Deep 3	Offshore Deep 4	Offshore Deep 5	Offshore Deep 6	Offshore Deep 7
New England		23%	15%	16%	20%	23%	25%	15%	17%	21%	24%	26%	15%	17%	21%	24%	26%
New York		22%	18%	20%	24%	28%	30%	19%	21%	25%	29%		19%	21%	25%	30%	32%
Middle Atlantic		23%	18%	20%	24%	28%		19%	21%	25%	30%		19%	21%	25%	30%	
East North Central		24%	19%	21%	26%			21%	24%	30%	36%	39%	20%	22%	28%	33%	40%
West North Central	37%	25%	20%	22%	26%	30%		20%	22%	27%	32%		20%	23%	27%	32%	
South Atlantic		23%	23%	26%	31%	37%	40%	27%	30%	36%	43%		27%	30%	36%	43%	
Florida		23%						19%	21%				18%	21%	25%		
East South Central		23%	25%	29%	35%	41%	44%										
West South Central	37%	24%	24%	27%	33%	38%	42%	27%	30%				27%	30%			
Texas	36%	25%	19%	21%	25%	29%	32%	20%	22%	26%				22%	26%		
Upper Mountain States	31%	22%	25%	28%	33%	39%	42%										
Arizona, New Mexico, Colorado	43%	28%	22%	24%	29%	34%	37%										
Pacific	18%	16%	25%	28%	33%	39%	42%	26%	29%	35%	41%	44%	26%	29%	35%	41%	45%
California	53%	28%	14%	16%	19%	22%	24%	15%	17%	20%	24%	25%	15%	17%	20%	24%	26%

Note: Author's calculations based on IPM (2010).

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